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Research Program on Fractured Petroleum Reservoirs

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RESERVOIR ENGINEERING RESEARCH INSTITUTE

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DOE Program Manager: Rhonda Patterson Lindsey

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April 1, through June 30, 1994

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RESERVOIR ENGINEERING RESEARCH INSTITUTE

PROJECT 3

ANALYSIS OF IMMISCIBLE GAS - OIL DRAINAGE EXPERIMENTS IN LAYERED POROUS MEDIA

2Q.94

April 1, through June 30, 1994

ABBAS FIROOZABADI

ANALYSIS OF IMMISCIBLE GAS - OIL DRAINAGE EXPERIMENTS IN LAYERED POROUS MEDIA

SUMMARY

Gas-oil gravity drainage experiments in a layered system which were carried out in 1993 are analyzed. The analysis reveals that the shape of the gas relative permeability governs the arrival of the gas phases at the interface between the layers. Based on the analysis of the experiments, it is concluded that, unlike gravity drainage in homogeneous media, the gravity drainage performance of layered media for the unstable downward gas fingering case, is sensitive to the gas relative permeability curve.

INTRODUCTION

Both theoretical analysis[1] and experimental data[2] reveal that gravity drainage in layered media has two important features - 1) gas may finger through the less permeable top layer to reach the more permeable bottom layer, and 2) due to capillary pressure contrast between layers, the recovery from the less permeable layers becomes inefficient. In this report, the experiments that were reported in Ref. 2 will be analyzed by using a numerical simulator. In the following, we will first present the measured capillary pressure of the Berea and sand layers and then provide the analysis.

CAPILLARY PRESSURE DATA

The capillary pressure of the sand and Berea layers were measured by varying capillary pressure at the inlet face. This could be achieved by lowering the position of the outlet valve across the vertical direction when the porous media column is also held vertical. Seven to eight $P_c/\bar{S}_l$ measurements below the threshold height were measured. The details of the Pc measurements technique are provided in Ref. 3. Capillary pressures are given by the following expression[4],

$$P_c = P_c{}^o - \sigma \ln (S_o - S_{or})/(1 - S_{or}) \qquad (1)$$

For the Berea, $P_c{}^o = 0.37$ psi, $\sigma = 0.145$ psi, and $S_{or} = 0.26$. The parameters of sand layer capillary pressure are; $P_c{}^o = 0.128$ psi, $\sigma = 0.067$ psi and $S_{or} = 0.085$. The capillary pressure curves were measured for normal decane/air fluid system at a room temperature of 76° F. Figure 1 shows a plot of the data. We also performed drainage experiments for single columns of the sand and Berea to estimate the liquid phase relative permeability curve. The procedure for liquid phase relative permeability calculations from drainage data are also presented in Reference 3. The relative permeability of both Berea and sand layers are well represented by $K_{rl} = S_l^{*3}$, where S_l^* is the normalized liquid saturation given by $S_l^* = (S_o - S_{or})/(1 - S_{or})$. For a homogeneous medium, infinite gas mobility is a good assumption.

ANALYSIS OF EXPERIMENTS

With capillary pressure, liquid phase relative permeability, absolute permeability, and fluid density and viscosity data, one may attempt to compare the measured drainage behavior of the two - layer system with the simulated results. As an example, consider the drainage performance from Tests 2 and 3 with the production level was fixed 67.1 cm below the Berea/sand interface. Figure 2 shows both production and rate data for the duplicate tests. As a first attempt, gas phase relative permeability was assumed to be given by $K_{rg} = (1-S_l^*)^3$. Figure 2 depicts the simulation results (denoted by N_g=3) and the data. This figure reveals that the arrival of the gas phase to the interface realizes after 20 minutes, whereas the experimental value is less than 10 minutes. The simulation gives a peak production rate of 350 cm^3/hr which is higher than experimental value of 275 cm^3/hr. Gas phase relative permeability is the only unmeasured parameter used in the simulation. In our theoretical work[1], we assumed an infinite gas mobility which allows the gas to arrive instantaneously at the interface when the flow is unstable. The criterion of downward stable displacement from capillary and gravity forces is $k_2/k_1 > 1-h_2^o/h_1$. where k_2 and k_1 are the absolute permeability of the top and bottom layers, and h_2^o the threshold capillary height of the top layer, and h_1 is the height of the bottom layer. Since h_2^o = 36 cm, and h_1 = 67.1 cm for Tests 2 and 3, $k_2/k_1 > 0.46$ results in stable drainage. The actual permeability ratio is k_2/k_1 = 0.95 md/42 d = 0.022. Therefore, gas fingering should realize. With few trials, a gas phase relative permeability was found which would give the correct arrival of the gas phase at the interface and provide maximum production rate of 275 cm^3/hr - the same as the experimental value of maximum production rate. The simulation results for the modified gas relative permeability denoted by "simulation" are also shown in Figure 2. Note that one may readjust further gas phase relative permeability to improve the match between measured and simulated results. Both gas phase relative permeability curves, $k_{rg} = (1-S_l^*)^3$, and the adjusted curve are shown in Figure 3.

We have also plotted the production from the Berea top layer. Figure 4 shows the calculated results for three cases; for two cases, the layered system with different gas phase relative permeabilities were used. For the third case, we assumed a homogeneous Berea column with the properties of the Berea layer. Only the production of the portion corresponding to the top Berea layer is plotted in Figure 4. This figure clearly shows that due to capillary contrast between the two layers, the drainage performance of the Berea layer when located on top of of a more permeable layer is less efficient than a homogeneous system. Note that in Figure 2 as well as Figure 4, the effect of gas phase relative permeabilities of Figure 3 on production is not significant.

For the Berea top layer in the layered system, after 11 1/2 days, the recovery is 60.3 percent; but in a homogeneous system, the recovery is 70.0 percent. At capillary/gravity equilibrium, the recovery of the Berea top layer will, of course, be the same (which may take a long time, more than the economic life of a reservoir).

We now present the analysis of the other tests.

<u>TESTS 15 AND 16</u> - Similar to Tests 2 and 3, in Test 15 and 16, the production was held at 67.1 cm below the interface, but production was kept at 1 cm^3/min, until the rate of drainage decreased below this value. Then the production valve was fully opened. According to Ref. 1, when $q_o < k_2 A\Delta\rho/\mu o$, the gas oil gravity drainage should be stable. Since $k_2 A\Delta\rho/\mu o$ = 2.0 cm^3/min, the drainage process should be stable. The gas front in Test 15 and 16 arrived at the interface at t= 220 minutes, at which the Berea layer had desaturated to 62 percent. The experiments in line with theory show stable gravity drainage.

<u>TESTS 5 AND 6</u> - In these two tests, the production outlet was fixed 33.6 cm below interface. According to criterion of Ref. 1, the gravity drainage process should be stable. Figure 5 shows the data and the simulation results. Measured P_c and k_{rl} data were used in simluation. The adjusted gas relative permeability was used as input to the simulator. The agreemtn between data and simulation results is fair. Since h_2^o = 36 cm, there was no production from the sand layer. Both the simulated and measured saturations of the top Berea layer at t=50 hr are about 45 percent.

<u>TESTS 7 AND 9</u> - In these tests, the production outlet was fixed at 44.6 cm below the interface. Therefore, according to the criterion of Ref. 1, the gas oil gravity drainage should be unstable. For both

tests, gas front reached the interface at t=105 minutes implying that a quick fingering did not occur. However, the production data reveal an unstable gravity drainage process. Figure 6 depicts the measured data and simulation results. The agreement between the two is good. The simulation results show that gas arrives at the interface at t=70 minutes which is less than the measured value of 105 minutes. Use of $k_{rg}=(1-S_l^*)^3$ instead of adjusted relative permeability of Figure 3 gives an arrival time of 130 minutes and over estimates the production in the 180 to 500 minutes substantially (results not shown).

TESTS 10, 11, AND 12 - In all these three tests, the production level was fixed at 78.1 cm below the interface. Figure 7 compares the data and simulation results. The arrival of the gas phase at the interface is less than 10 minutes both in the experiments and simulation. The maximum production rate is also nearly the same (from the experiments and simulation). Except in the 30 to 70 minute period, the simulation results and data are in good agreement. However, the use of $K_{rg} = (1-S_l^*)^3$ gives a gas arrival time of 35 minutes and a maximum drainage rate of 450 cm^3/hr at 85 minutes. These results are substantially different from the data.

TEST 13 - In this test, the production level was fixed at 98.1 cm below the interface. Since h_l^o = 13 cm, the gas should flow out of the sand column at some time. Figure 8 gives the data and simulation results for both gas relative permeability curves of Figure 8. Note that the adjusted curve of Figure 8 gives a reasonable match with data, and the $k_{rg} = (1-S_l^*)^3$ curve gives a longer time for gas arrival at the interface and a higher maximum production rate than the experimental data.

CONCLUSIONS

The experimental data and their brief analysis presented in this report leads to the following conclusions.

1 - Capillary pressure contrast between layers reduces the drainage preface of layered media.

2 - Unlike homogeneous media, where drainage characteristics is weakly related to gas relative permeability, the drainage of a layered system may be influenced by the gas phase relative permeability. The arrival of the gas phase at the interface between layers is a strong function of gas phase relative permeability.

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3. Firoozabadi, A., and Markest, T.: "Laboratory Study of Reinfilteration for Gas-Layered Systems in Fractured Porous Media," RERI 4Q.91, 1991
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NOMENCLATURE

A - crosssectional area

h - column thickness

h^o - threshold height

k_{rl} - liquid phase relation permeability

k_{rg} - gas phase relative permeability

P_c - capillary pressure

P_c^o - threshold capillary pressure

S_l - liquid saturation

S_l^* - normalized liquid saturation, $S_l^* = (S_l - S_{or})/(1 - S_{or})$

S_{or} - residual liquid saturation

$\bar{S}_l$ - average liquid saturation

σ - parameter of capillary pressure model

Subscipts

1- bottom sand layer

2- top Berea layer

Fig. 1 - Measured Capillary Pressures of Berea and Sand Layers

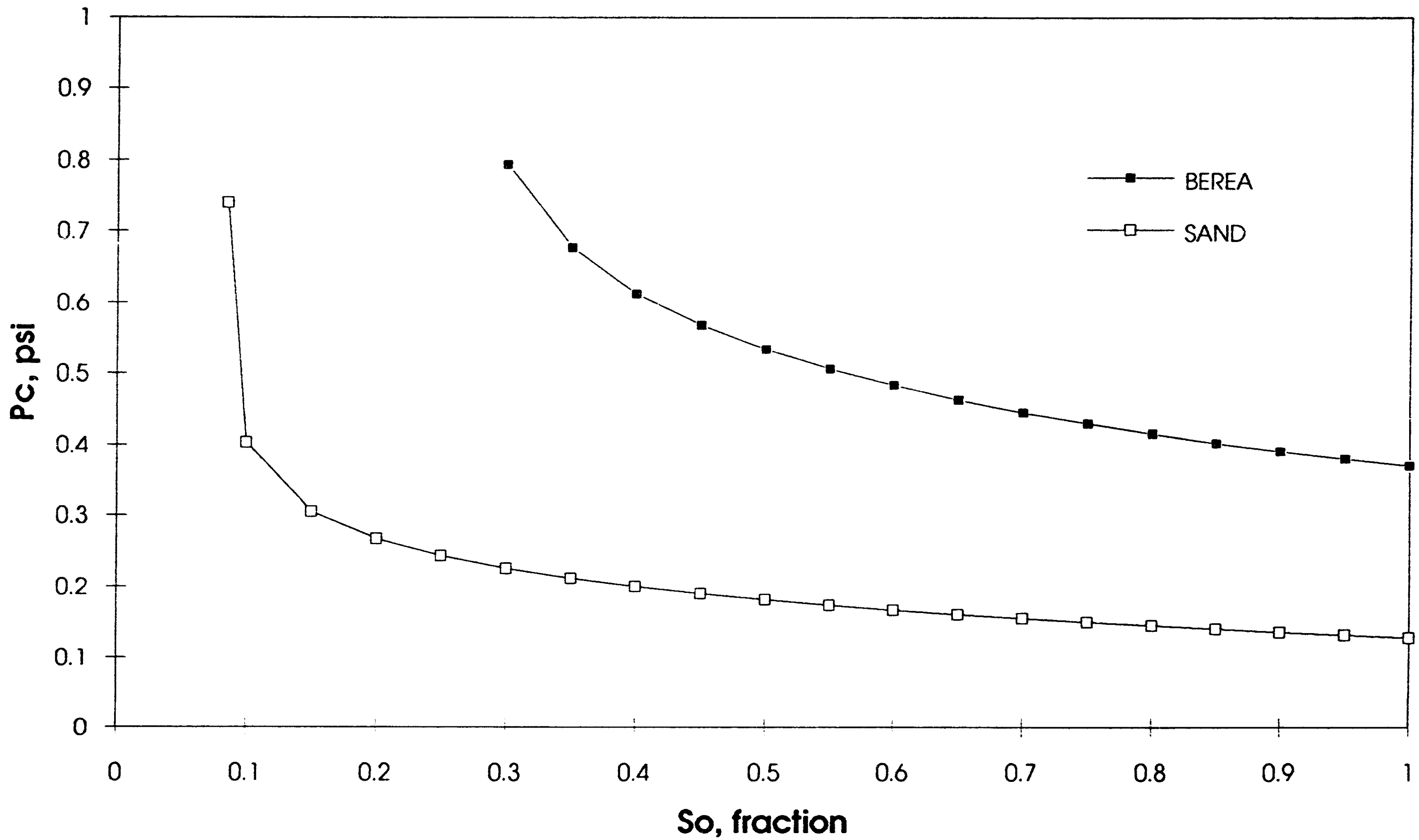


Fig. 2 - Comparison of the simulated and measured production and rate for tests 2 and 3.

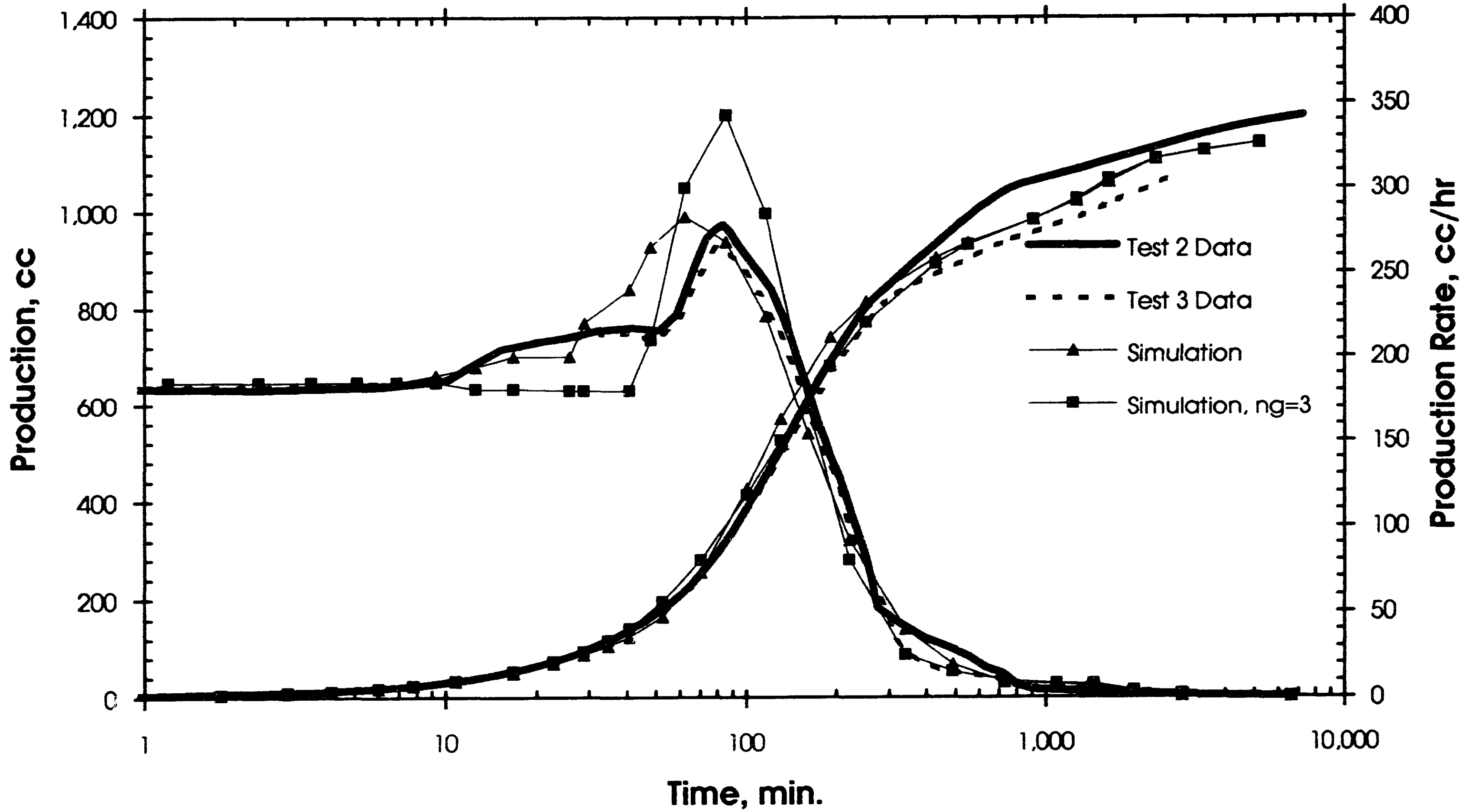


Fig. 3 - Gas relative permeabilities

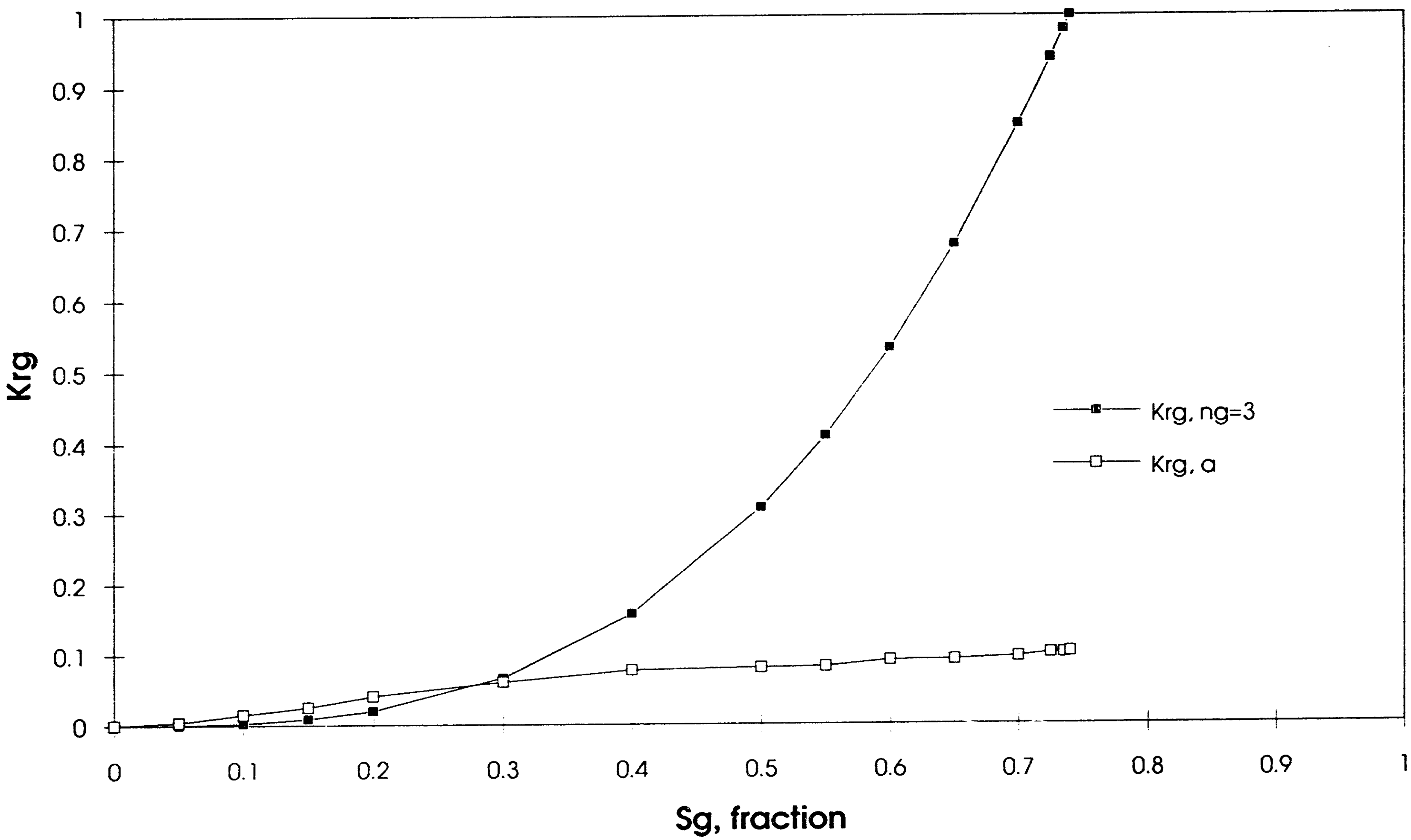


Fig. 4 - Calculated production from the Berea Top layer.

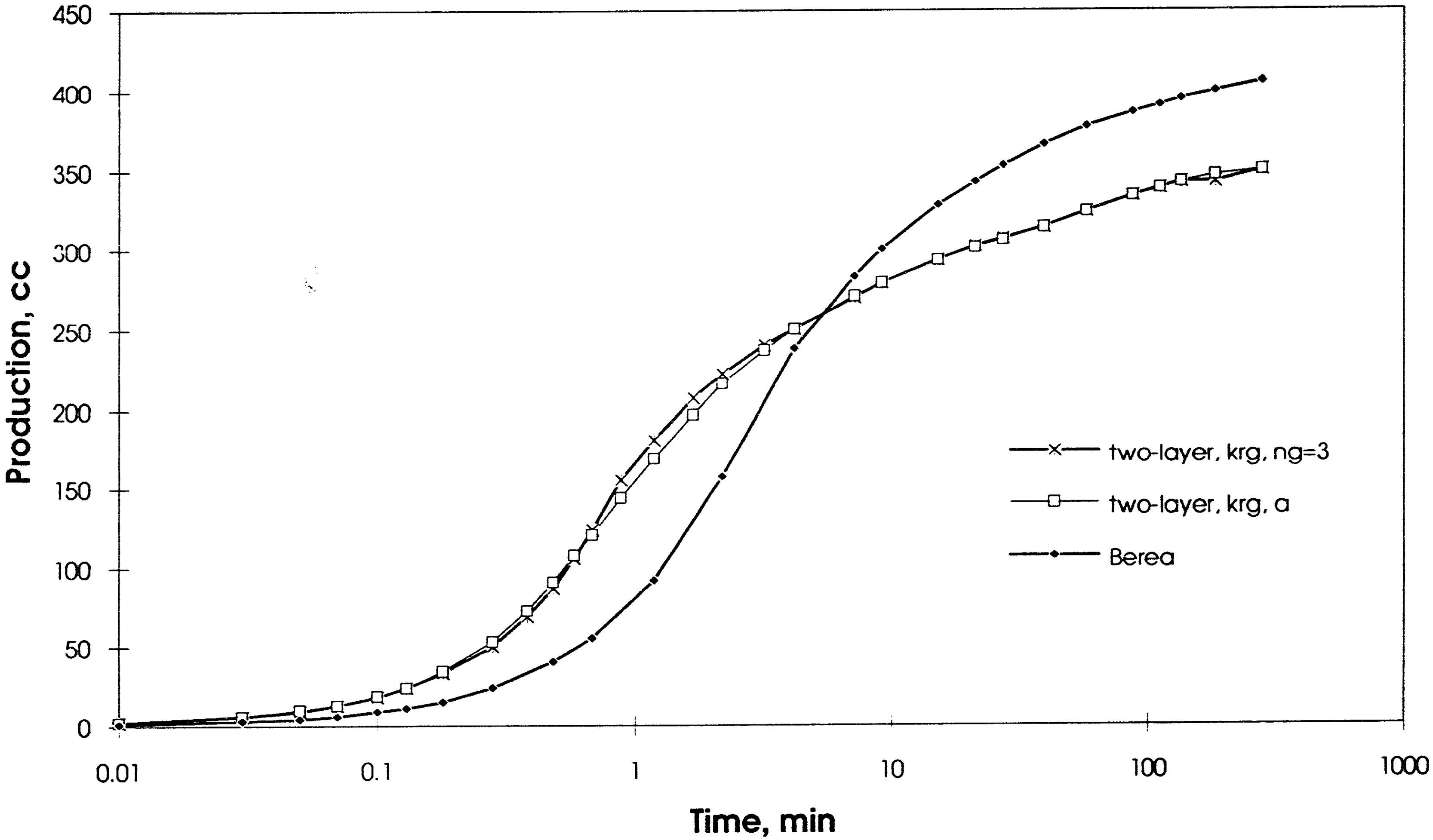


Fig. 5 - Comparison of the simulated and measured production and rate for tests 5 and 6.

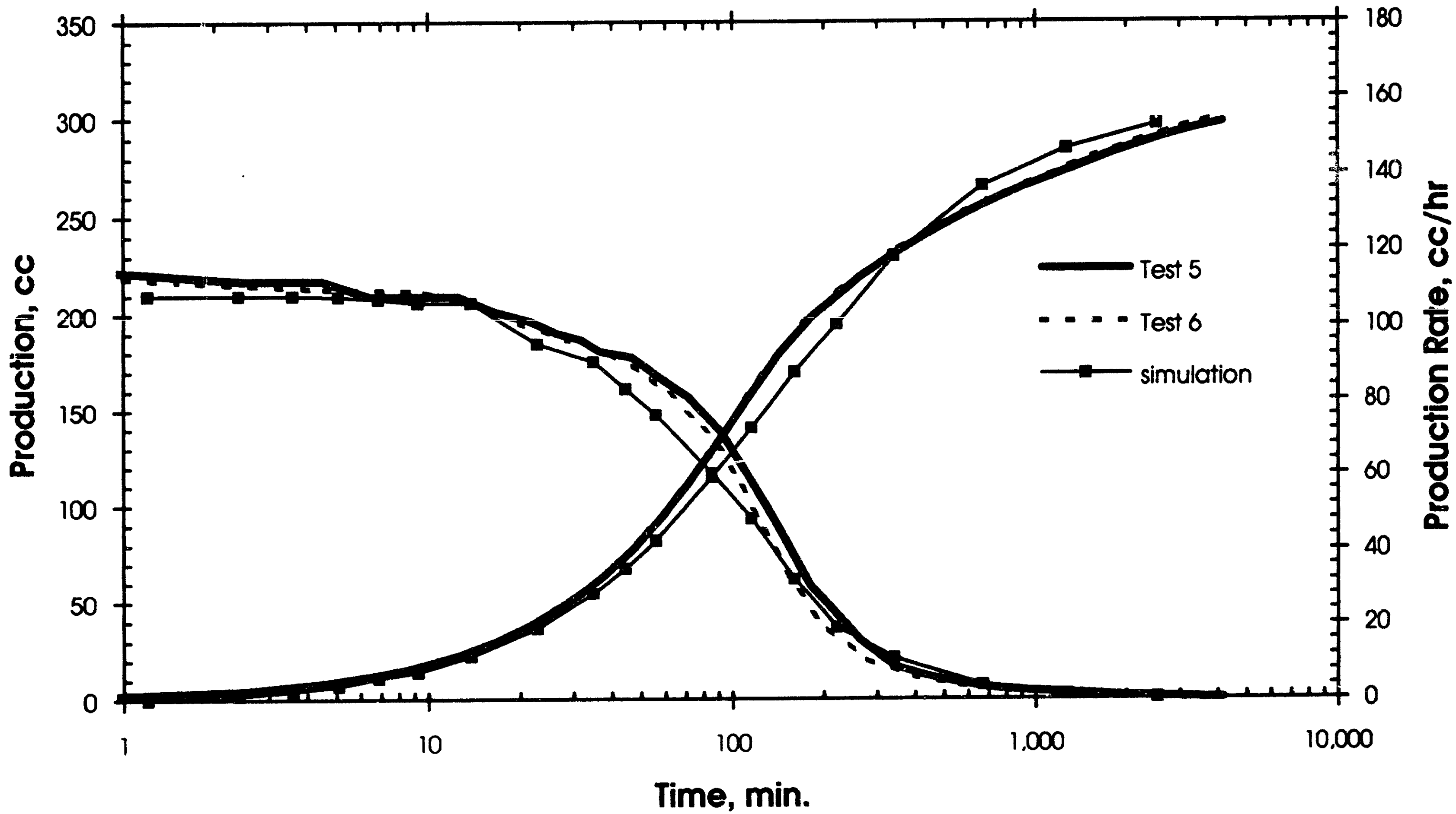


Fig. 6 - Comparison of the simulated and measured production and rate for tests 7 and 9.

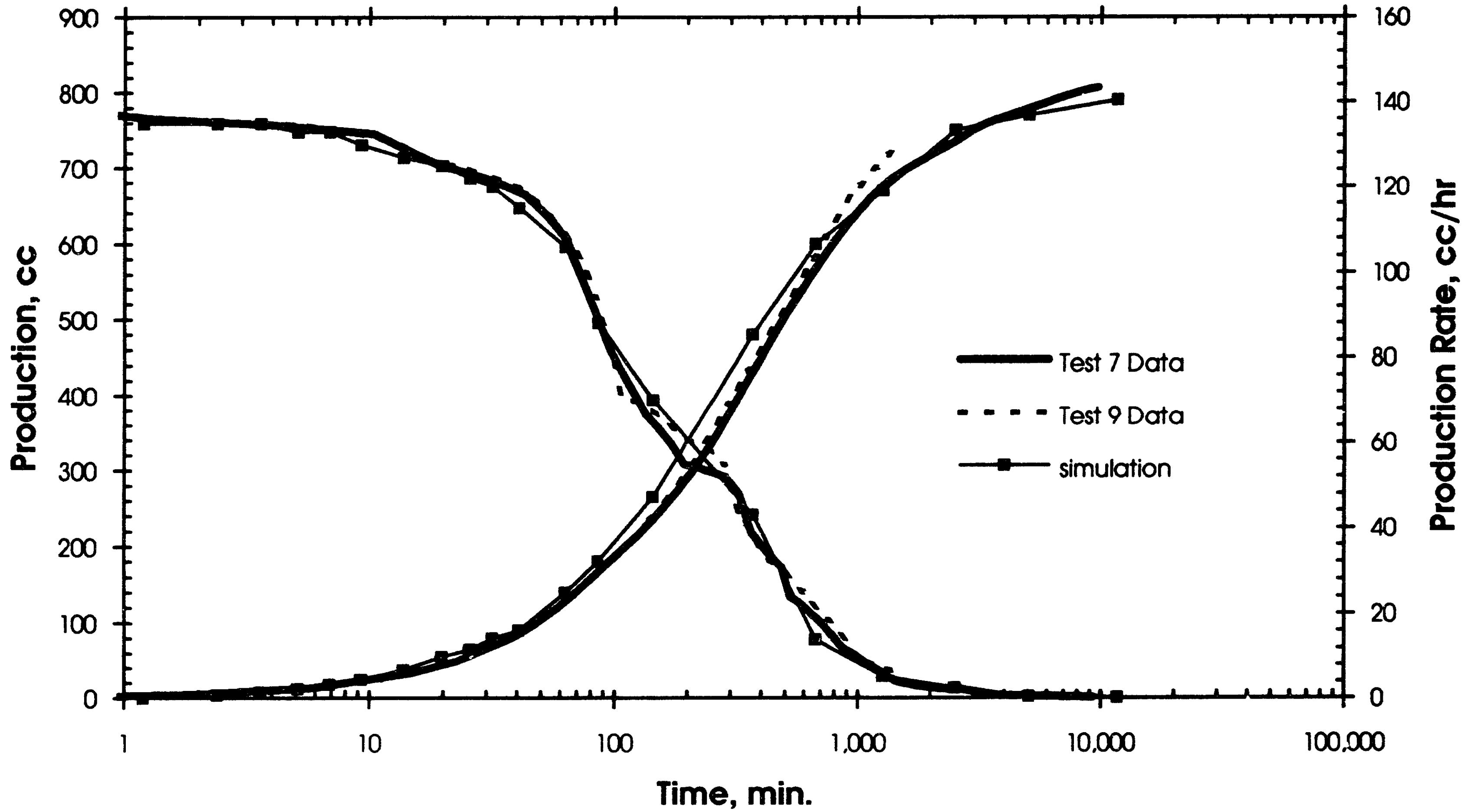


Fig. 7 - Comparison of the simulated and measured production and rate for tests 10, 11, and 12.

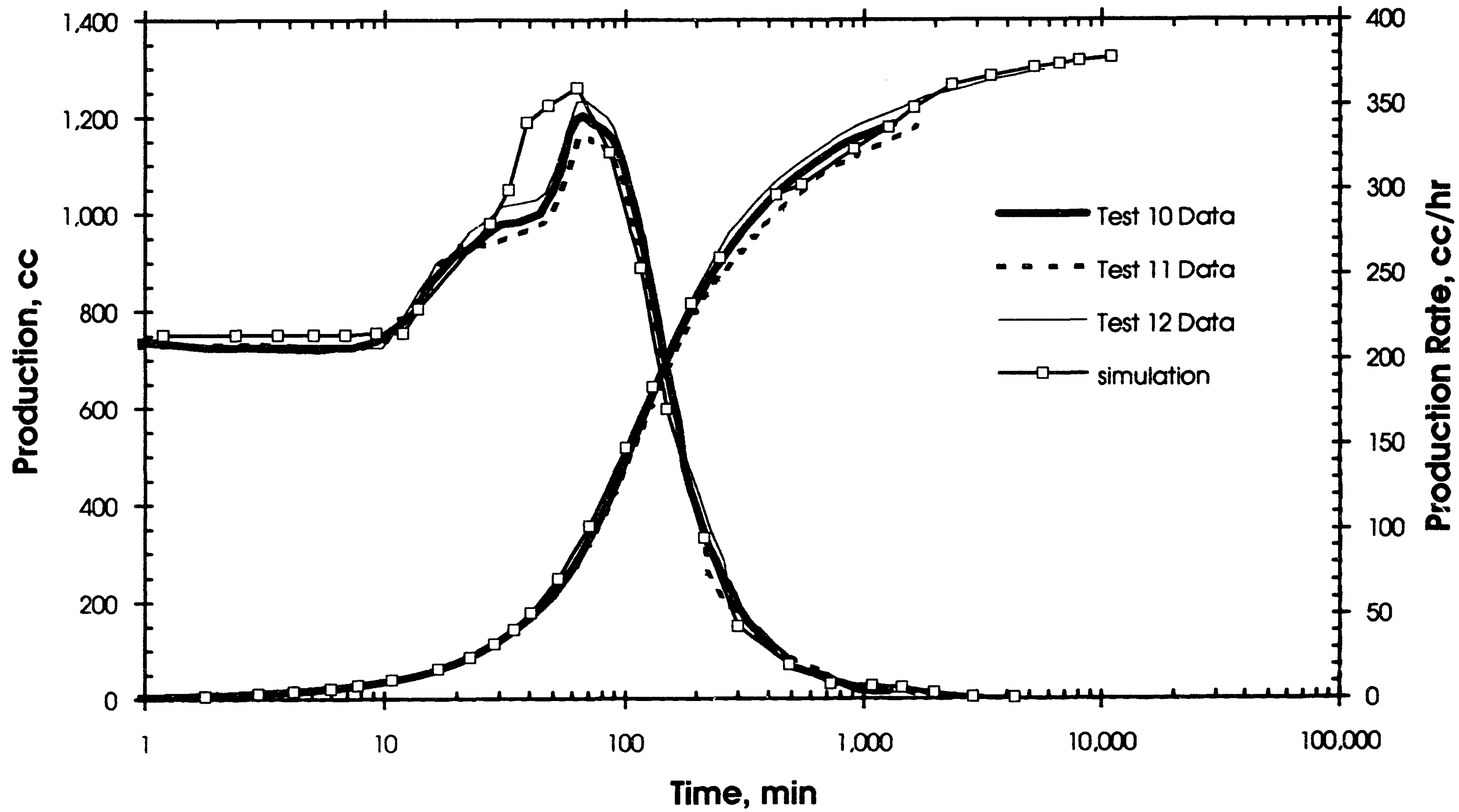
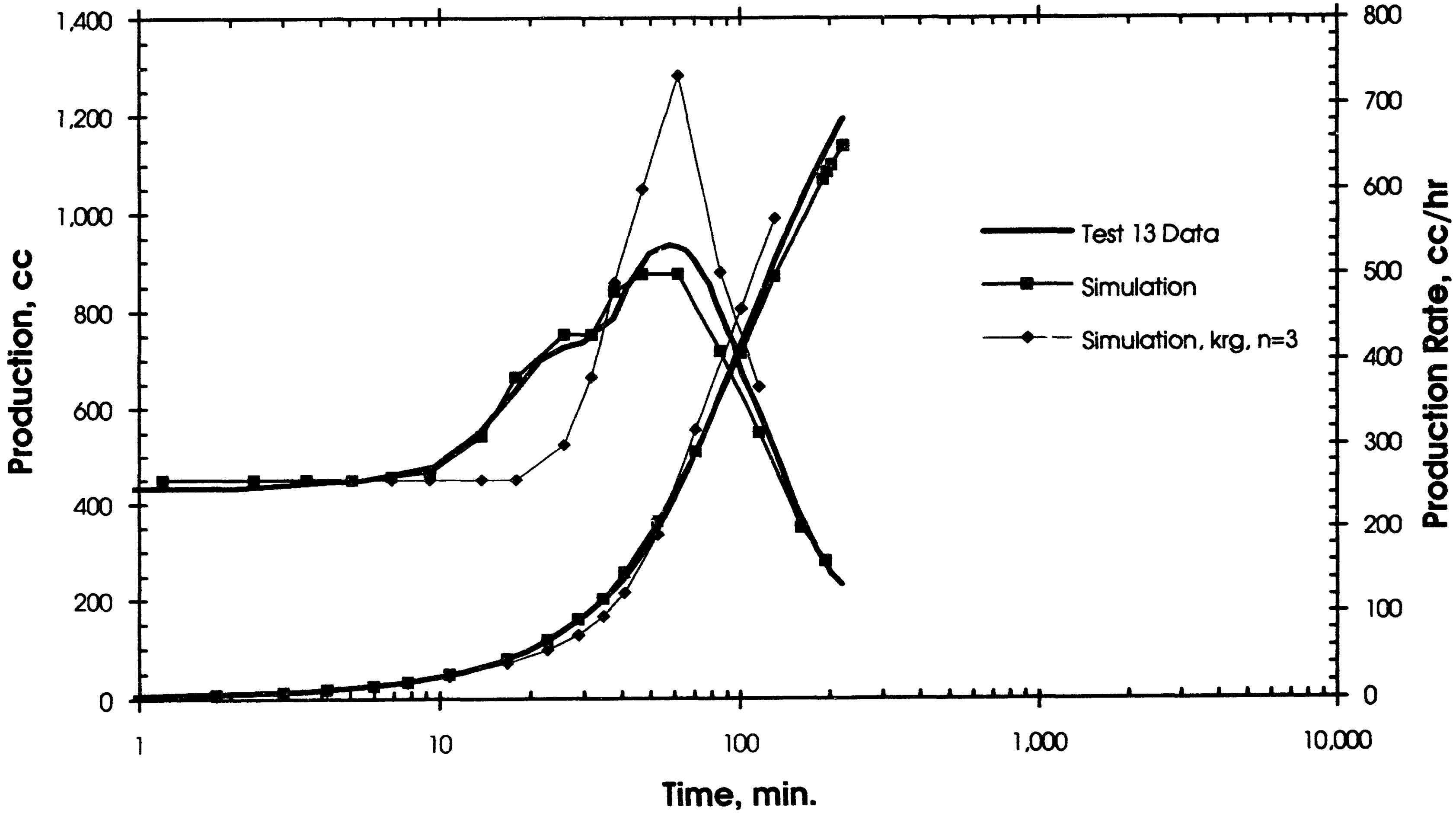


Fig. 8 - Comparison of the simulated and measured production and rate data for test 13.



RESERVOIR ENGINEERING RESEARCH INSTITUTE

PROJECT 4

Waterfluid Performance of Tight Rock in Fractured and Layered Reservoirs: Part I - Fractured Reservoirs

2Q.94

April 1, through June 30, 1994

ANDREW ARONSON
ABBAS FIROOZABADI

WATERFLOOD PERFORMANCE OF TIGHT ROCK IN FRACTURED AND LAYERED RESERVOIRS

PART I - FRACTURED RESERVOIRS

Summary

In a large number of fractured and layered reservoirs, tight rock may contain a significant amount of oil. The contribution of the tight matrix in fractured petroleum reservoirs, and of the tight layers in layered reservoirs is an unresolved issue. In this report, the results of water displacement in fractured porous media with a matrix permeability of the order 0.01 md, and a matrix porosity of about 5 percent is presented. A preliminary test reveals that a recovery of 25 percent is achieved over a period of 28 days. At the termination of the test, the rate of oil recovery from the tight matrix was about 0.3 percent of PV per day.

Introduction

A large number of fractured petroleum reservoirs are comprised of tight matrix rock and fractured networks. Many layered reservoirs also contain tight layers. The thickness of the tight layers can vary from less than a foot to 10 ft or more. The permeability of the tight rock is of the order 0.01 md and the porosity can vary from 3 to 10 percent. The fundamental issue is the contribution of the tight matrix in fractured reservoirs and the tight layer in layered reservoirs. Current literature, in most cases, neglects the contribution of the tight rock matrix.

The purpose of this work is the study of water displacement efficiency in fractured and layered reservoirs with tight matrix and tight layers, respectively. Part 1 of the project addresses the issue of water injection in fractured reservoirs with tight matrix. In part 2, water injection in layered reservoirs will be studied. In this report, we will present the results of the first test.

Experimental

Apparatus: A schematic of the experimental apparatus is shown in Figure 1. The setup consists of a steel coreholder 45 inches in length with an external diameter of 4.0 in. and an internal diameter of 3.366 in. Six core samples, all with finely machined external diameters of approximately 3.363 in., of varying lengths are held in place in the coreholder with pistons and threaded endcaps. The coreholder is oriented vertically. Plumbed to the bottom of the coreholder is an Isco constant flowrate syringe pump. The effluent from the core passes through the top endcap, which is connected to a tube which terminates in an inverted graduated cylinder, used for measurement of the amount of oil produced. Connected in parallel to the injection and production lines is a system for evacuating the coreholder.

Test Procedure: The coreholder was assembled with Austin chalk cores # 1-5 and 7 in descending order. Table 1 gives the dimensions, porosities, permeabilities, and pore volumes of the cores. Two columns of porosity values are given in Table 1. One set of values are those measured at an overburden pressure of 500 psig. Further tests on a single core show that the porosity is dependent on the overburden pressure. The second porosity values, and corresponding pore volumes, were estimated by assuming an analogous percentage porosity increase (12.5 %) with reduction in overburden to atmospheric, as compared with the tests on the single core. The total pore volume for the cores (1-5 and 7) using ϕ at 500 psig is 255 cm^3 and the value using the larger porosities is 287 cm^3.

The system was placed under vacuum and heater tapes were applied to the coreholder to assist in desorption of nitrogen and air from the cores. The coreholder was heated to approximately 140°F and the system was evacuated at a pressure of 50 mTorr for about two weeks. At the termination of evacuation, the equilibrium pressure in the coreholder system was about 500 mTorr. The system was then saturated with nC_6, by first filling the isolated Isco pump and then injecting the liquid into the coreholder. Saturation was performed stepwise. After an initial large injection of liquid, small volumes were injected, causing the system pressure to rise. This increase in pressure aided in saturating the smallest pores of the rock. A total of 400 cm^3 of nC_6 were used to saturate the system over a one week period. The injection water was prepared by grinding up a spare piece of chalk into pebble size chunks, placing these in distilled, deionized water at a ratio of 1 g rock/100 cm^3 water, and allowing 13 days for equilibration. This was done to prevent the dissolution of the core samples during the water injection experiment. Test 1, which was conducted at a room temperature of 75°F, is described next.

Observations and Results - Test 1 - 3 cm^3/hr Injection Rate: The production of nC_6 versus time is plotted in Figure 2. The rate of water injection in the waterflood experiment is approximately 3 cm^3/hr. The plot shows that during the initial 60 hours that nC_6 production follows the injection rate. At an injection volume of about 140 cm^3 a sharp change in the slope of the curve occurs. This corresponds to the water breakthrough point. After this point, nC_6 is produced at a rate of approximately 2-3 cm^3/day. At 195 hours, water injection is stopped and imbibition is allowed to proceed for about 11 days (262 hr). At 457 hours, water injection is resumed. Once again, production of pure nC_6 occurs for approximately 7 hours until water breakthrough occurs, after which a slightly reduced rate of nC_6 production is seen. At 555 hours, water injection is again halted to allow for imbibition. After 93 hours of imbibition, the water flood is resumed. This is followed by a short period of pure oil production (2 hr) and subsequent return to even slower production of nC_6 at a rate of about 1 cm^3/day. The total amount of nC_6 produced is about 180 cm^3.

After completion of the experiment, an attempt was made to measure the fracture volume/dead space of the system. It was found that the the narrow tolerances between the outer diameter of the chalk samples and the inner diameter of the coreholder created a situation where a minimal amount of liquid flowed from the system when both sides were opened to atmospheric pressure (gravity flow). The 0.003 in nominal difference in diameters corresponds to a fracture gap of 38 μm and suggests a very small fracture volume, approximately 10.4 cm^3. Upon further investigation (removal of the top endcap and piston) it was found that a gap between the stack of cores approximately three-quarters of an inch was present and filled with liquid. The volume of this liquid was approximately 100 cm^3. Therefore, with an initial total system pore volume of 400 cm^3 and assuming that the 100 cm^3 of nC_6 from the dead space was produced, a total of about 80 cm^3 nC_6 was produced from the cores, corresponding to 26.7% recovery. An interesting observation was made when the cores were removed from the coreholder. Initially the surfaces were wet. But due to the volatility of nC_6, the cores rapidly dried (in about 15-30 seconds) leaving behind dark veins, which were possibly water filled microfractures. The excess space in the coreholder has been eliminated and a repeat experiment is currently underway.

<u>Concluding Remark</u>

This preliminary test reveals that 25 percent of the oil in the tight matrix blocks can be recovered by water displacement. At the end of the test (after t = 28 days), the rate of oil production was 0.3 percent of the PV.

Table 1. Properties of the Austin Chalk Core Samples

Core#	L, in	k, md	ϕ(500psig),%	PV, cm^3	ϕ(atm),%	PV, cm^3
1	7.290	0.012	4.3	45.63	4.8	51.33
2	5.830	0.017	4.2	35.64	4.7	40.10
3	7.100	0.034	4.3	44.44	4.8	49.99
4	6.120	0.007	4.7	41.87	5.3	47.10
5	6.028	0.042	4.2	36.85	4.7	41.46
6	5.435	0.009	3.5	27.69	3.9	31.15
7	7.875	0.013	4.4	50.44	5.0	56.74
8	5.758	0.007	3.8	31.85	4.3	35.83

Figure 1. Austin Chalk Experimental Setup

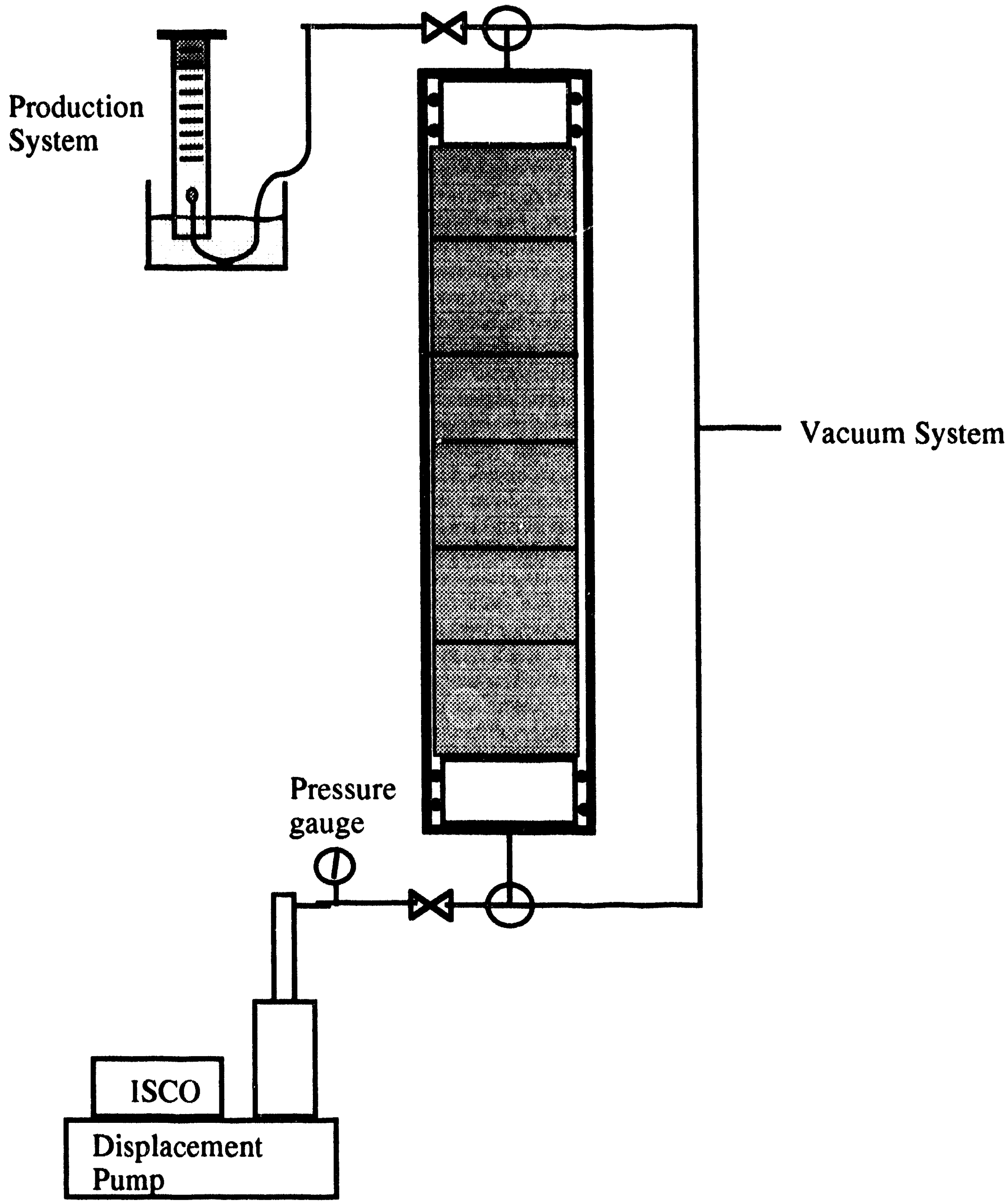
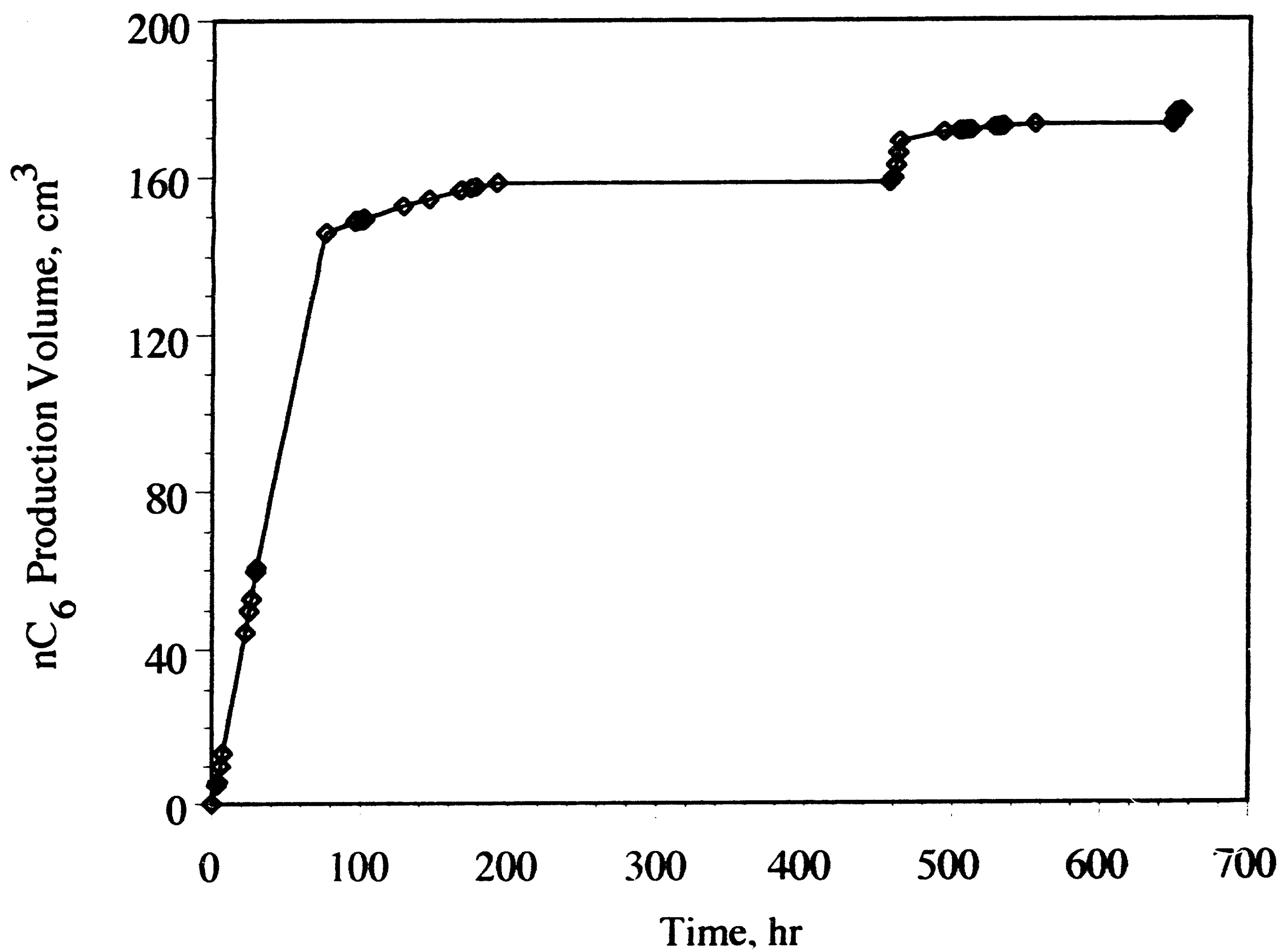


Figure 2. Waterflood Production of nC_6 for Austin Chalk Expt #1



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